NOT FOR PUBLICATION APPENDIX

Appendix: Potential Confounders

A1.1 Preliminary Discussion

In this online appendix we evaluate the potential for confounding factors to influence our results. We are interested, in particular, in potential bias of our main estimates of merit-order and out-of-merit changes. The following sections consider natural gas prices, non-thermal generation, entry and exit of generating units, imports, and demand. Although it is important to go through these potential confounding factors carefully, we end up concluding that overall our estimates are unlikely to be affected by changes in these other market conditions.

Before discussing the specific concerns, it is useful to clarify exactly what we mean by bias. Consider, for example, our estimates of merit-order effects. Conceptually, what we hope to capture with our merit-order estimates is the change in generation from the SONGS closure that would have occurred if there were no transmission constraints or other physical limitations of the grid. Implicitly, we want to hold everything else constant in this calculation so that the estimates reflect the true causal impact of the closure. Our empirical strategy is to build this counterfactual by constructing the unit-level generation curves using data from before the closure, and then to move up these curves by the amount of lost generation. An illustration is provided in Figure A1.

Thus, in some sense, no change to the market in 2012 could "bias" these results. Our merit-order estimates are constructed using pre-closure data only, so they provide predicted changes in generation given the market conditions prior to 2012. Since there is no information from 2012 in these estimates, it does not make sense to think about them being biased by anything that happened in 2012.

An alternative approach for estimation would have been to use post-closure data to construct generation curves, and then to move down these curves by the amount of generation SONGS would have produced had it stayed open. Both approaches build a counterfactual for the SONGS closure, but we prefer our approach because it facilitates a straightforward decomposition of the impact into merit-order and out-of-merit effects (see Figure A1). Nonetheless, using pre-closure data to construct our counterfactual raises important questions about changes in market conditions. The primary objective of the following sections is to work through the different potential confounders. Even though market conditions are constantly changing, we end up concluding that overall our merit-order estimates are unlikely to be meaningfully biased during the twelve months following the closure. As more time passes, conditions become considerably different from the pre-closure period; for this reason we focus on merit-order estimates for the twelve months following the closure.

Conceptually, we want our out-of-merit estimates to reflect the difference between actual generation and the generation that would have occurred if there were no transmission constraints or other physical limitations of the grid. These estimates rely on the same counterfactual constructed for the merit-order estimates, so all the same questions arise about potential confounders.

There is also an additional potential concern for our out-of-merit estimates. The pattern of price differentials make it clear that transmission constraints and/or other physical limitations of the grid were more likely to bind post-closure. This change has been widely attributed to the SONGS closure itself. The pattern of observed prices, both over time, and across California regions tends to support this interpretation. Nonetheless, it is important to consider the possibility there was some other simultaneous change in market conditions that influenced these constraints. We investigate this possibility in the following sections and confirm that changes in confounding factors are unlikely to play much of a role.

A1.2 Changes in Natural Gas Prices

Figure A2 shows that there were large changes in natural gas prices during our sample period. Overall, natural gas prices were around 30% lower in 2012 than they were in 2011. These lower prices reduced the cost of replacing the lost generation from SONGS, relative to what one would have calculated based on 2011 prices. We emphasize this point in describing our results and use 2012 prices when quantifying the cost of increased thermal generation.

In addition, it is natural to ask whether these price changes could somehow bias our estimates of merit-order and out-of-merit changes. In this section we evaluate several potential concerns and, at the same time, discuss closely related potential concerns about changes in the price of permits for Southern California's cap-and-trade program for nitrogen oxides (NOx). Permit prices affect the marginal cost of thermal generation and thus raise very similar questions to changes in natural gas prices, so it makes sense to address both at the same time. Overall, the evidence suggests that our results are unlikely to be meaningfully affected by these price changes.

The main potential concern is changes in the ordering of plants. Our unit-level regressions reflect the ordering of plants along the marginal cost curve. Plants with low heat rates are more efficient, producing large amounts of electricity per unit of fuel input, so these plants operate all the time. Plants with higher heat rates are less efficient, so appear at the high end of the marginal cost curve and operate less frequently. If the changes in natural gas prices affected this ordering, this could bias our estimates of merit-order and out-of-merit effects. We could make mistakes, for example, in reporting which plants met the lost generation from SONGS.

Although this is a reasonable concern, there are several reasons why we would not expect much change in the merit order. First, there is very little coal or other fossil fuels in the California electricity market, and thus little scope for inter-fuel changes in the ordering of plants. Nationwide the decrease in natural gas prices has led to widespread substitution of natural gas for coal (Cullen and Mansur, 2013), but essentially all of this has occured outside the state of California. Second, a large fraction of California generation operates at close to zero marginal cost. This includes nuclear, 'run-of-the-river' hydro, geothermal, wind, and solar. These resources are ahead of natural gas in the queue, regardless of whether natural gas costs \$2 or \$7 per MMBtu. Third, the ordering of natural gas plants is largely unaffected by natural gas prices. The part of the marginal cost curve made up of by natural gas plants should be thought of, essentially, as an ordering of plants by heat rate. A decrease in natural gas prices reduces the marginal cost of generation for all plants, but the *ordering* is largely unaffected.

We say 'largely unaffected' because marginal cost also depends on NOx emissions and variable operations and maintenance which vary across plants. However, these components are small compared to the cost of fuel so the merit order is almost exactly a monotonic ranking of plants by heat rate. Take NOx prices, for example. Under the RECLAIM program, certain generators in and around Los Angeles must remit permits corresponding to their NOx emissions. As it turns out, however, NOx permit prices were low enough during our sample period that they are unlikely to affect the ordering of plants.[17] In our data, the mean emissions rates for the Los Angeles area plants is 0.4 pounds per MWh (median 0.2 pounds per MWh). The average prices for NOx permits was \$2493/ton in 2010, \$1612/ton in 2011, and \$1180/ton in 2012 (all in 2013 dollars), implying that NOx credit payments make up only a small portion of the plants' marginal costs.[18]

A more subtle concern would be differential changes in natural gas prices between the North

[17]We obtain annual average NOx prices from the Regional Clean Air Incentives Market ("RECLAIM") annual reports for 2006-present. Higher frequency prices are not publicly available. We use the prices of credits traded in the same year as the compliance year.

[18]The mean marginal cost would therefore be less than \$0.60 in all three years, compared to wholesale electricity prices that are typically above \$30. A small number of units have substantially higher NOx rates; the highest rate we observe is 5 pounds per MWh.

and South. However, as can be seen in Figure A2, natural gas prices are quite similar in the North and South during the entire period. This makes sense given the network of existing pipelines as well as available storage, which can smooth out short-run capacity constraints in transmission. Although not visible in the figure, prices in the North decreased from the pre- to post-period approximately 2% more than in the South. This is a relatively small change, so we would not expect it to have much impact on the ordering of plants.

A1.3 Changes in Non-Thermal Generation

Between 2011 and 2012 there were also significant changes in electricity generation from hydro and renewables. Perhaps most importantly, 2012 was an unusually bad year for hydroelectric generation. The snowpack in 2012 was only half of the historical average level, and total hydroelectric generation in 2012 was less than 2/3rds generation in the previous year.[19] At the same time, there were also substantial increases in wind and solar generation. Almost 700 megawatts of wind and solar capacity were added in 2012 (CAISO 2013b), resulting in large percentage increases in generation from wind and solar.[20] This section discusses how these changes in non-thermal generation could potentially impact our estimates or affect how the results are interpreted.

As with the changes in natural gas prices, it is worth emphasizing that these changes are exogenous and should not be viewed as being caused by the SONGS closure. Year-to-year variation in hydroelectric generation is driven by idiosyncratic variation in precipitation. And, while new renewables capacity investments do respond to market conditions, it takes at least several years for planning and permitting a new site. The new wind and solar facilities that came online in 2012 were first envisioned in the early 2000s, long before there was any indication of potential safety concerns with SONGS.

It is also important to remember that we measure merit-order effects using *net* system demand. When calculating demand for our unit-level regressions, we start with system-wide but then subtract from it all electricity generated by these non-thermal resources. Figure A3 shows a histogram of this hourly residual demand for each of these two periods, using the same bin width definition as in the regressions. Panel A shows one year of the pre-period and Panel B the post-period. Total generation from CEMS unit clearly shifts up substantially in the post-period to fill in for SONGS. However, the shape of the distribution

[19]For historic snowpack levels see the Snow Water Equivalents data from the Department of Water Resources at http://cdec.water.ca.gov/cdecapp/snowapp/sweq.action. On April 1, 2012, the snowpack was at 54% of the historical April 1 average.

[20]Geothermal and other renewables experienced essentially no change between 2011 and 2012.

also changes – because of concurrent shifts, for instance in changes to renewables and hydro generation.

Because these changes to renewables and hydro are exogenous, we do not want our estimated out-of-merit effects to be attributed to changes in these other resources. This exogeneity assumption makes sense for wind, solar, and non-dispatchable hydro, because their marginal cost of operation is near zero – they are always included at the top of the merit order. The same could be said for electricity generation from California's one other nuclear power plant, Diablo Canyon. Thus changes in generation and/or entry and exit from non-thermal resources will affect the interpretation of our results, but will not introduce bias.

Dispatchable hydroelectric generation is somewhat harder to think about, but it is also unlikely to be affecting our results. Year-to-variation in precipitation determines total hydroelectric generation, but operators have some flexibility as to *when* these resources are utilized. Short-run generation decisions are determined by a complex dynamic optimization problem. Operators respond to current and expected market conditions, trading off between current prices and the shadow value of the remaining water in the reservoir. None of this is particularly problematic for our analysis because operators are presumably behaving similarly both before and after the SONGS closure. Moreover, the generation curves in Figure 5 indicate only a modest amount of intertemporal substitution toward high demand periods.

A related question is how changes in non-thermal generation could have changed the likelihood that the transmission constraints were binding, thus indirectly impacting the ordering of thermal resources. This is potentially problematic because we would like to attribute the observed out-of-merit effects to transmission constraints caused by the SONGS outage. Although this is an important consideration, the decrease in hydroelectric generation would have, if anything, made transmission constraints *less* likely to bind. Hydroelectric plants are located primarily in the North,[21] so the decrease in hydroelectric generation in 2012 would have, if anything, actually reduced the need for North-South transmission.

Similarly, the changes in wind and solar generation, while large percentage increases, represent small changes when compared to the entire market. Wind and solar generation statewide increased by 0.17 million, and 0.04 million MWh per month, respectively, in 2012. Total monthly generation in California in 2012 was almost 17 million MWh, so these increases combined represent only about 1% of total generation. Moreover, most of the new capacity was in the South, so if anything, these additions would have made transmission constraints

[21] According to CAISO (2013D), approximately 80% of summer capacity is in the North.

less likely to bind.

A1.4 Entry and Exit of Thermal Units

From 2010 to 2012, a number of thermal generating units opened or closed, and in this section we discuss the impact of this entry and exit on the interpretation of our estimates. Our main results focus on a balanced panel of units, restricting the sample to those units that were continually in service during our sample period plus Huntington Beach units 3 and 4, which operated for most of this period, but were converted to synchronous condensers in 2013. Excluding units that enter and exit simplifies the analysis and interpretation but also raises two potential concerns. First, our results could be biased if the entry and exit were endogenous to the closure of SONGS. In particular, it would be a causal effect of SONGS that we are failing to capture. Second, for entry and exit that is either endogenous or exogenous, a separate concern is that these changes could somehow have affected transmission congestion. This could then bias our out-of-merit effects.

Entry and exit in 2010 and 2011 is clearly exogenous, since the closure of SONGS was unanticipated. We exclude five units that exited in 2010; these units had accounted for 1 to 2% of generation before their closure. We additionally exclude units that enter in 2010 or 2011, before the SONGS closure was anticipated; these units accounted for 3.5% of generation in 2012. We simply do not have enough pre-period data from these plants to include them in the analysis.

Endogenous entry and exit in 2012 are almost certainly not a concern given the short time horizon. New units take years to plan and permit, and the closure of SONGS was unexpected. To verify this, we examined siting documents from the California Energy Commission for the units that opened in 2012. Altogether, these units accounted for less than 1% of CEMS generation in 2012. Where we were able to locate the siting documents, we found that applications had been filed in 2008 or 2009, long before the SONGS closure. It is possible that these openings may have been accelerated by the SONGS closure, but we are unaware of any specific cases. It is true that in the long run, we would expect endogenous entry, but 2012 is still much too early.[22]

More plausibly, the SONGS outage could have delayed plant exit. To the best of our knowledge, the only such case is the extension of operations at Huntington Beach's units 3 and

[22] A related possibility is that existing units made capital investments to change their heat rate or capacity. If caused by the SONGS closure, this would be one of the mechanisms through which our effects operate. If not caused by SONGS, it would confound our results only if it affected transmission congestion.

4. These two units were expected to retire about the same time that SONGS closed, but remained open in 2012 to provide additional generation and voltage support in Southern California (CAISO 2013b). These units are in our sample, so this generation is reflected in our results. In addition, for these units we estimate an extra year's worth of fixed operations and maintenance costs to be around $4 million.[23] This cost is small in comparison to the generation cost increase caused by the SONGS closure. It is also very small in comparison to the fixed operations and maintenance costs at SONGS itself; this is in part because the two Huntington Beach units are smaller, and in part because fixed O&M costs are much lower at natural gas units than at nuclear units.

Finally, any entry and exit that did occur exogenously, even if it impacted transmission congestion, cannot explain the out-of-merit effects that we estimate. Net entry during the twelve months following the SONGS closure was larger in the North than the South, by approximately 130 MWh on average each hour. Taken by itself, this would have changed congestion in the same direction as the closure of SONGS. However, the difference in net entry between the South and North is smaller than the change in generation from large-scale hydro. As such, the overall impact of these combined changes to generation (from net entry, large-scale hydro, and other renewables) could not have been to exacerbate congestion into Southern California.[24]

A1.5 Imports

Imports make up 30% of total electricity supply in California. In calculating our merit-order effects we have implicitly assumed that none of the lost generation from SONGS is met by out-of-state generation. Whether or not this is a reasonable assumption depends on the impact of the SONGS closure on prices and on the elasticity of supply for imports. Our results suggest that price impacts were likely modest. During most hours equilibrium in the California electricity market occurs along the long inelastic part of the marginal cost curve, so one would not have expected the SONGS closure to have a substantial impact on prices. In addition, during the hours in which equilibrium occurs along the steep part of the marginal cost curve, there was limited available interstate transmission to bring in additional out-of-state supply.

[23]The Cost of Generation Model from CEC (2010) reports an annual fixed O&M cost for California combustion turbine plants of 8.3 $/kW-yr, in 2010 dollars (it does not report a number for steam boilers). We multiplied this by a capacity of 440 MW and translated into current dollars.

[24]For this calculation, we assume that 80% of the fall in hydro generation was from Northern resources, based on the capacity data in CAISO (2013d). We also make the conservative assumption that the entire increase in solar and wind generation was from Southern resources.

Empirically, the elasticity of supply for imports appears to be relatively low. As shown in Figure 3, imports increase with system demand, but not very much, and most of the increase occurs at relatively low demand quantiles. Above the median system-wide demand, there is essentially no observable increase in imports. Averaging across all hours, imports increase by an average of 519 megawatt hours when total demand increases by 2,150 MWh. This is equivalent to 25% of the lost generation from SONGS. This suggests that we could reduce our merit-order estimates in Panel A of Table 3 by 25%. The regional pattern of generation impacts would still be similar, but all of the estimates would only be about three-quarters as large. For the cost estimates, however, we do not expect much of an adjustment needs to be made. Since the in-state generation marginal cost curve is quite elastic in most hours, the cost of out-of-state generation much have been close to the marginal cost of the in-state generation. As a result, the cost estimates we report in the paper should be close to the true change in total cost accounting for imports.

Interestingly, the change in imports during weekday summer afternoons and high demand hours was much lower. During weekday summer afternoons, imports in 2012 increased on average by only 90 megawatt hours, and during high demand hours the increase was less than 10 megawatt hours. This is consistent with interstate transmission constraints or other physical limitations of the grid preventing larger increases in imports during these hours. Alternatively, it could simply reflect the fact that demand is correlated across states, i.e. it tends to be hot in Nevada and California at the same time, and so the elasticity of supply for imports becomes very inelastic in these periods.

From the perspective of interpreting our results it doesn't particularly matter *why* imports are not responding more. This lack of responsiveness in high demand hours means that the estimates in Panels B and C of Table 4 are approximately correct. Incorporating imports would reduce our estimates in these panels by only 4% and 1%, respectively, reflecting the relatively small portion of the lost generation from SONGS that appears to have been met with imports.

A1.6 Electricity Demand

Statewide demand for electricity was slightly higher in 2012 than 2011 due to warm weather. We calculate our merit-order effects using the distribution of system-wide demand in 2012, so our estimates reflect this higher overall level of demand. Hence, there is no sense in which this aggregate change in electricity demand is biasing our estimates. Still, in the paper, we would like to attribute the increase in transmission constraints to the SONGS closure, so it would be worth knowing if the changes in electricity demand are large enough to provide an alternative explanation.

Had SONGS closed during a cooler year, it would have been less expensive to meet the lost generation, and transmission constraints would have been less binding. While this is undoubtedly true, the same could be said about hydroelectric generation, natural gas prices, and other factors. Throughout the analysis we have tried where possible to have our estimates reflect actual market conditions in 2012.

A related question is how to think about demand response. Implicitly, our analysis assumes that electricity demand is perfectly inelastic. We calculate our merit-order effects by moving along the generation curves by 2,150 MWhs, the entire lost generation from SONGS. This assumes that demand is perfectly inelastic. Although this assumption is common in the literature, it is obviously not exactly right. Although the vast majority of customers do not face real-time prices, retail electricity prices do respond month-to-month to change in generation costs. Moreover, there are some industrial customers who face prices that update more frequently. The size of the demand response depends on how much prices changed and the price elasticity of demand. The SONGS closure shifts the marginal cost curve to the left, increasing prices. Our results suggest, however, that in the vast majority of hours this price impact would have been fairly modest, because demand was crossing a fairly elastic portion of the marginal cost curve. Moreover, most estimates of the price elasticity of demand suggest that even in the medium-term, demand is not very elastic.[25] Thus evaluating the change in supply required to make up the entire 2,150 MWhs of lost generation is likely a very good approximation.

A more subtle concern is whether differential changes in demand across region could have impacted transmission constraints. To evaluate this, we obtained hourly demand for three geographic regions within California, corresponding closely to the Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric service territories (the former in the North, and the latter two in the South). In Figure A4, we show the total weekly quantity demanded for all three regions across time. While not large, there does appear to be a divergence in the summer of 2012 between the PG&E and SCE quantities, reflecting a warmer than average summer in the South. However, in Figure A5, we show preliminary evidence that this is unlikely to explain much of the price difference we see in the post-period. This graph plots the price difference between the SP26 and NP15 pricing regions, as well as the demand difference between the South (SCE plus SDG&E) and the North (PG&E).

[25] Ito (2014), for example, finds a price elasticity of less than -0.10 with respect to retail prices for a sample of California households.

While the demand difference between the North and South increased in late 2012, the price difference increased much sooner and persisted much longer.

To more formally address the concern that our out-of-merit results could have been driven by the changes in demand, we examined results from an alternative specification in which we estimate equation (1) conditioning on the demand *difference* between North and South. Specifically, we calculate the difference between South (SCE plus SDG&E) and North (PG&E), then construct a series of equal-width bins. These bins are interacted with the demand bins in the unit-level generation regressions. The merit-order results (available upon request) are qualitatively similar to those in Table 3. The point estimates of the out-of-merit results are generally around 10% smaller than in Table 3, although they are not statistically different. This may indicate that a small portion of the congestion was attributable to the difference in demand.

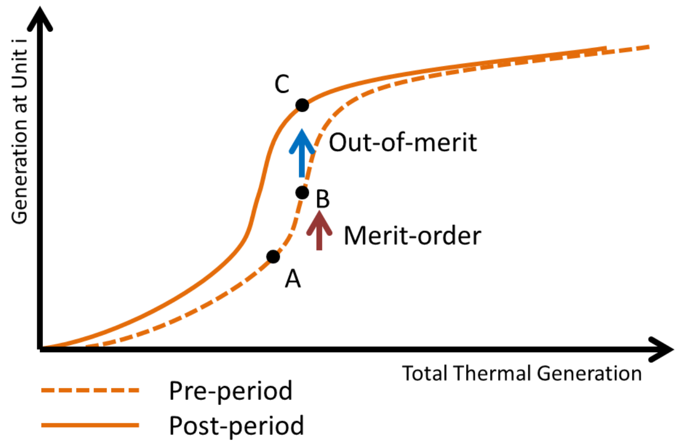
A1.7 Placebo Tests

To provide further evidence that the observed out-of-merit effects are unusual, and not driven by idiosyncratic unobservables, we next provide a series of placebo tests. We repeat our analysis six times, estimating the model as if SONGS had closed in different years (2006, 2007, ... and 2011). Figure A6 shows the out-of-merit changes for each placebo regression, with separate results (as in our main analysis) for all hours, weekday summer afternoons, and high demand hours.

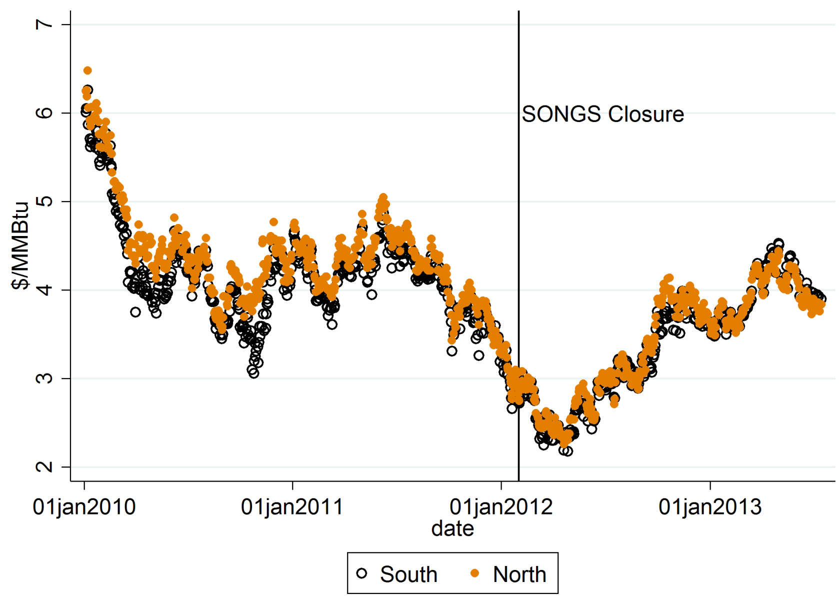
The figure shows that some of the estimated out-of-merit effects from other years are similar in size to the estimates for 2012. In 2007, for instance, the South saw positive out-of-merit changes, whereas the North saw negative changes. However, the results for 2012 differ more dramatically from the placebo results when one accounts for the unusual behavior at AES-owned facilities. In Figure A7, we again show six placebo tests, but based on estimates from a sample that excludes AES. In these results, the 2012 large positive changes in the South and large negative changes in the North are more apparent than in the previous figure.

Moreover, closer inspection of the out-of-merit results in other years shows that they are largely driven by extended outages at single plants, rather than by correlated changes across plants. To demonstrate this, Figure A8 shows a series of additional statistics from these placebo tests. In particular, we calculate the standard deviation, skewness, and kurtosis of the unit-level changes. For years with the largest out-of-merit changes (especially 2007 and 2009), the presence of outliers is clear in these diagnostics. These years have higher standard deviations, skewness (in absolute terms), and kurtosis than our main sample, indicating the presence of outliers. Overall, these placebo test results indicate that the pattern of results we see in 2012 is indeed unusual.

Appendix Figure A1: Merit-Order and Out-of-Merit Effects

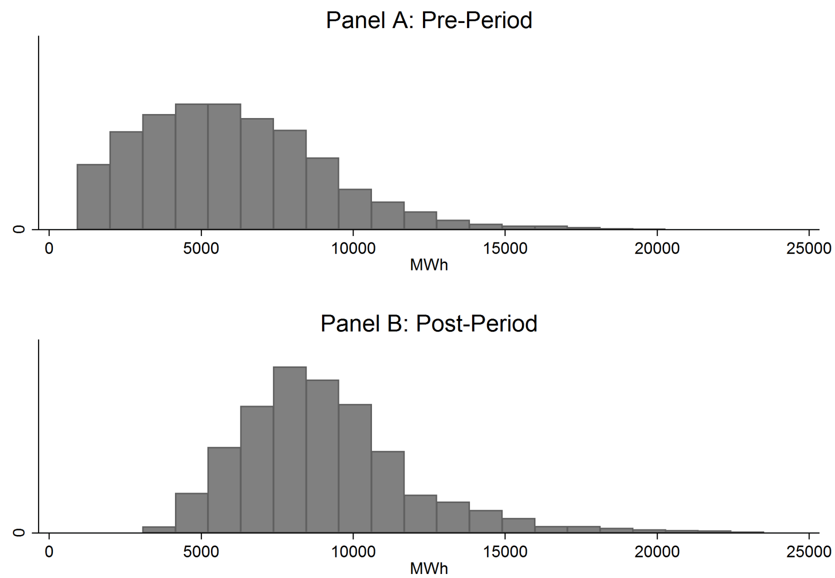


Appendix Figure A2: Natural Gas Prices, by Region



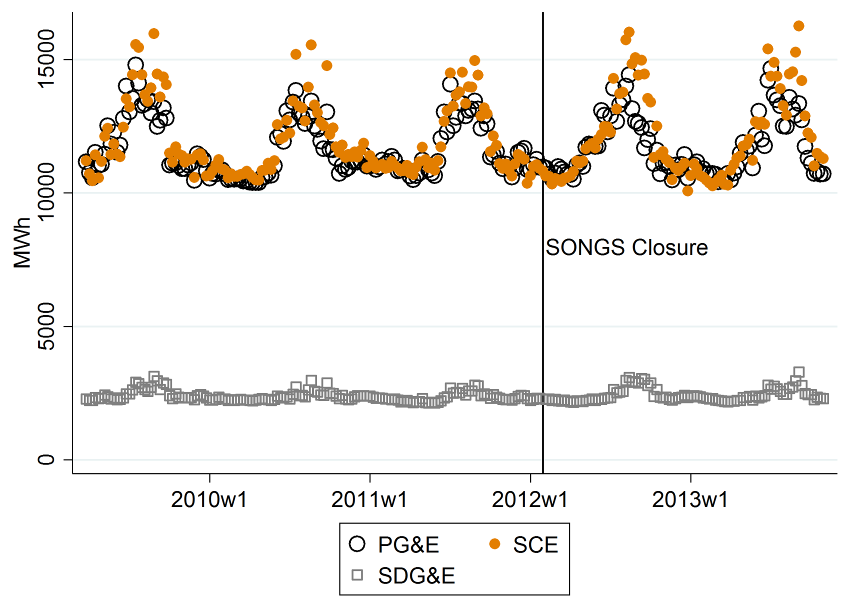
Note: This figure plots daily natural gas prices, in $/mmbtu, for Northern California (PG&E citygate) versus Southern California (SCG citygate). Data are from Platts Gas Daily.

Appendix Figure A3: Histogram of Hourly Total Generation



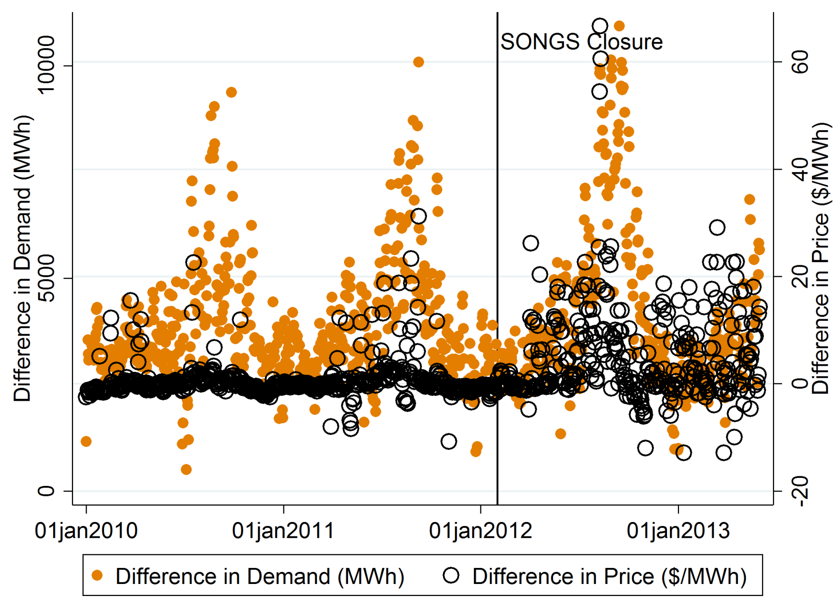
Note: This figure shows histograms of total hourly generation from CEMS units in the year leading up to the SONGS closure (Panel A) and in the year following the closure (Panel B). The shift to the right in Panel B reflects both the closure of SONGS and concurrent changes in non-thermal generation (especially hydro) and demand.

Appendix Figure A4: Regional Demand



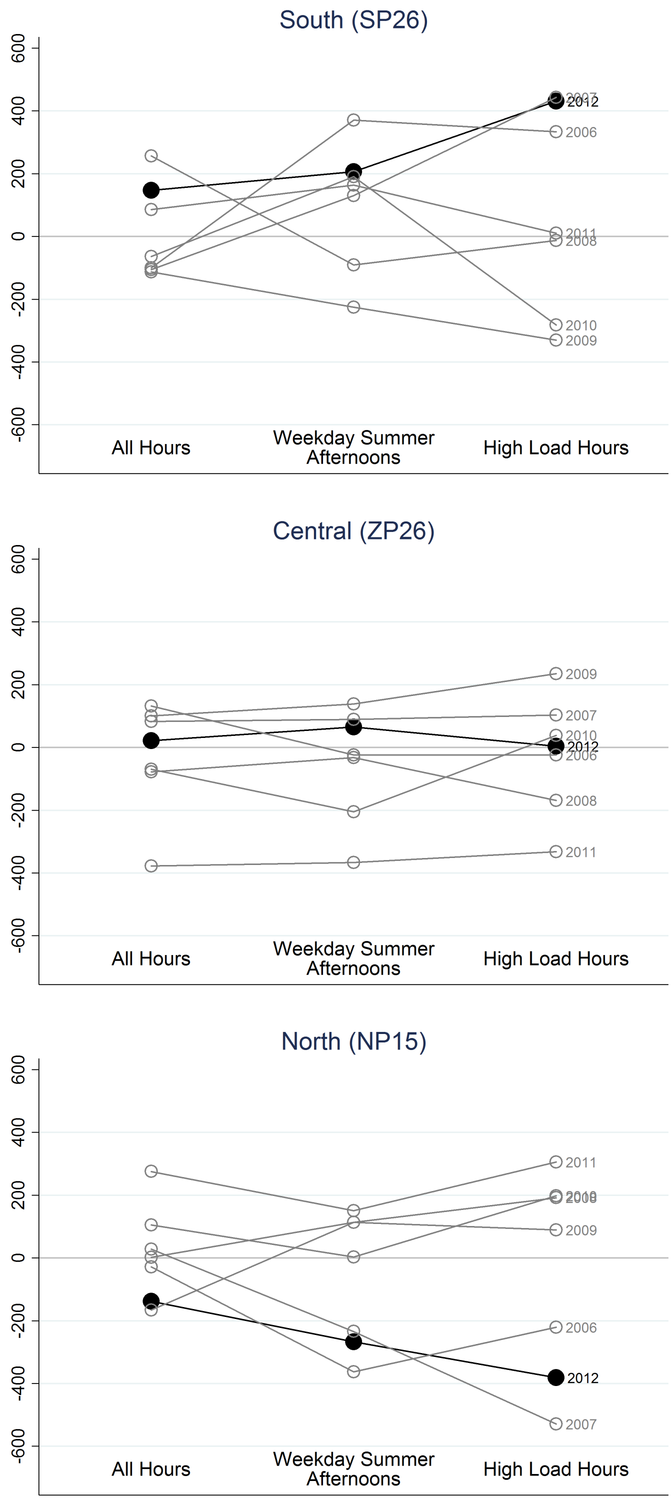
Note: This figure plots total quantity demanded by week for the three California investor-owned utilities. The vertical line shows the week the second SONGS unit went down. PG&E is roughly the Northern half of the state, SCE is the Southern half excluding the San Diego area, and SDG&E is the San Diego area.

Appendix Figure A5: Regional Demand and Price Differentials



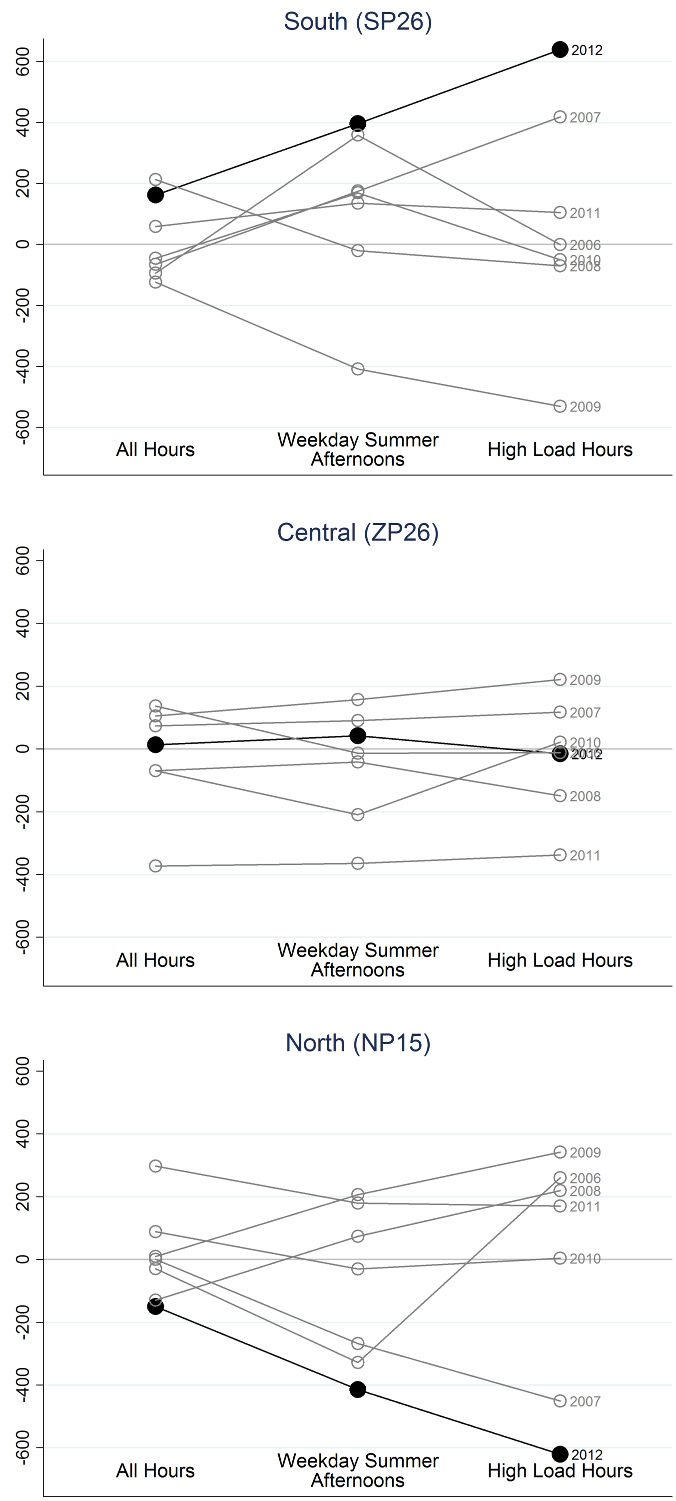
Note: This figure plots quantity demanded and price differentials at 3 pm daily between January 2009 and September 2013. Weekends are excluded. The vertical line shows the day the second SONGS unit went down (February 1, 2012).

Appendix Figure A6: Out-of-Merit Changes, by Year



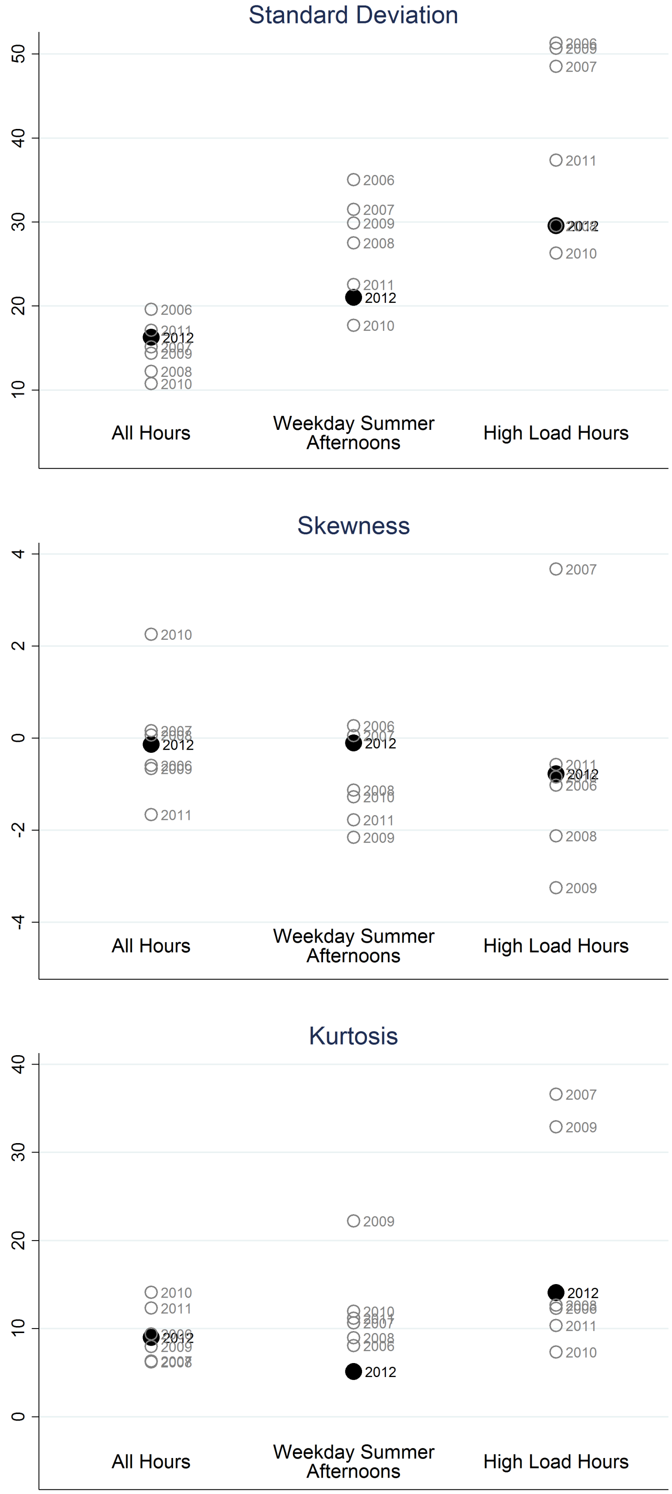
Note: These figures show out-of-merit estimates for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A7: Out-of-Merit Changes, without AES, by Year



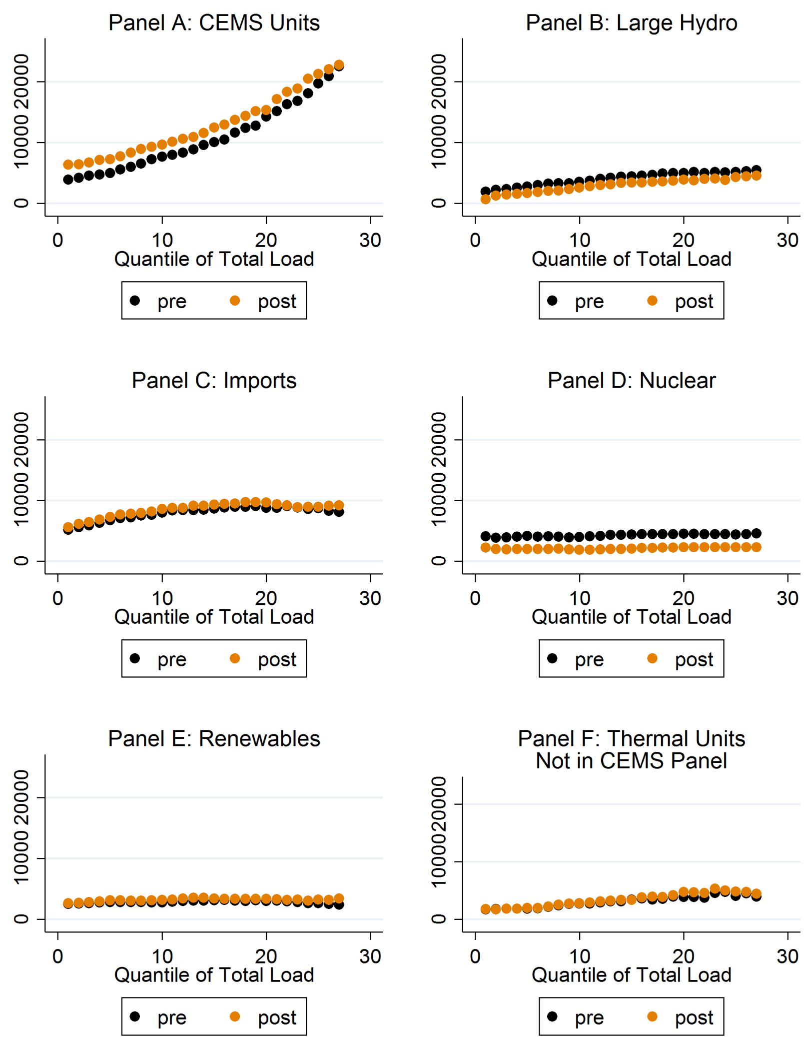
Note: These figures show out-of-merit effects based on estimates from a sample that excludes AES plants for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A8: Unit-Level Diagnostics, by Year



Note: These figures show unit-level diagnostics on the out-of-merit estimates, for the main sample of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A9: Generation Regressions by Category



Note: This figure was constructed in the same way as Figure 3 in the main text, but using data from both the pre-period and the post-period. The x-axis shows the quantile of total generation from all sources and the y-axis shows the average generation, in MWh, for that category of generation.

Appendix Table A1: Largest Plants not in CEMS

Plant Name	Operator	Sector	Prime Mover	County	Fuels	Million MWh in 2011	Million MWh in 2012	Summer Capacity, MW	Capacity Factor, 2011	Vintage
				Panel A: Non-Cogen Natural Gas Plants						
Humboldt Bay	PG&E	Utility	Internal Combust.	Humboldt	Natural Gas, Petroleum	0.5	0.4	167	0.32	1956*
Wheelabrator Shasta	Wheelabrator Environmental Systems	IPP	Steam Turbine	Shasta	Wood Waste	0.4	0.4	60	0.74	1987
Desert View Power	Desert View Power Inc	IPP	Steam Turbine	Riverside	Wood Waste, Nat. Gas, Tires	0.3	0.3	47	0.83	1991
SEGS IX	FPL	IPP	Steam Turbine	San Bernardino	Solar, Natural Gas	0.2	0.2	88	0.29	1990
SEGS VIII	FPL	IPP	Steam Turbine	San Bernardino	Solar, Natural Gas	0.2	0.2	88	0.28	1989
				Panel B: Cogen and Industrial Natural Gas Plants						
Watson Cogeneration	ARCO Products Co-Watson	Industrial	Combined cycle	Los Angeles	Nat. Gas, Other Gases, Waste Oil	3.0	3.1	398	0.86	1987
Crockett Cogen Project	Crockett Cogeneration	IPP Cogen	Combined cycle	Contra Costa	Natural Gas	1.8	1.7	247	0.84	1995
Sycamore Cogeneration	Sycamore Cogeneration Co	IPP Cogen	Gas turbine	Kern	Natural Gas	1.5	1.4	300	0.57	1987
Midway Sunset Cogen	Midway-Sunset Cogeneration Co	Industrial	Gas turbine	Kern	Natural Gas	1.4	1.4	219	0.72	1989
Kern River Cogeneration	Kern River Cogeneration Co	IPP Cogen	Gas turbine	Kern	Natural Gas	1.3	1.3	288	0.50	1985
				Panel C: Other Plants						
Diablo Canyon	PG&E	Utility	Steam Turbine	San Luis Obispo	Nuclear	18.6	17.7	2240	0.95	1985
San Onofre	SCE	Utility	Steam Turbine	San Diego	Nuclear	18.1	0.8	2150	0.96	1983
Geysers Unit 5-20	Geysers Power Co LLC	IPP	Steam Turbine	Sonoma	Geothermal	4.7	4.8	770	0.70	1971
Shasta	U S Bureau of Reclamation	Utility	Hydro	Shasta	Hydro	2.4	1.8	714	0.38	1944
Edward C Hyatt	CA Dept. of Water Resources	Utility	Hydro	Butte	Hydro	1.9	1.4	743	0.30	1968

Note: These data come from the U.S. Department of Energy *Power Plant Operations Report* and *Annual Electric Generator Report*. The table describes 2011 net generation for plants operating in California. "Largest" is defined according to net generation reported to EIA in 2011. Vintage refers to the year the plant started commercial operation. *Humboldt Bay was in CEMS until 2010 but dropped out after that, when the all of the plant's combustion turbine and steam boiler units were replaced with reciprocating engine generators.

Appendix Table A2: Most Affected Plants, Weekday Summer Afternoons

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Merit-Order Change (MWhs)	Out-of-Merit Change (MWhs)
			Panel A. Merit-Order Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	236	43
2	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	181	-213
3	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	152	125
4	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	89	118
5	AES Redondo	AES	Boiler	SP15	40/444/55/64	1348	88	-67
			Panel B. Out-of-Merit Increases, Top Five					
1	Coolwater	NRG	Comb Cyc / Boiler	SP15	36/38/38/38/41/42	636	30	158
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	152	125
3	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	89	118
4	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	54	98
5	Elk Hills	Occidental Petroleum	Comb Cyc	ZP26	26/27	548	11	86
			Panel C. Out-of-Merit Decreases, Top Five					
1	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	181	-213
2	Panoche	Energy Investors Fund	Combust Turbine	NP15	35/35/35/35	412	54	-105
3	Calpine Sutter	Calpine	Comb Cyc	NP15	25/26	564	60	-94
4	Los Esteros Critical	Calpine	Combust Turbine	NP15	37/37/37/38	186	28	-80
5	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	25	-76

Note: The regressions for this table are identical to those in Table 3, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in the CEMS data. Weekday summer afternoons include the hours 2 p.m. to 5 p.m. in months June through September. †EME refers to Edison Mission Energy.

Appendix Table A3: Including 2013

	Average Hourly Change, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Merit-Order Change in Net Generation (MWh)	883	301	950
	(19)	(17)	(18)
Out-of-Merit Change in Net Generation (MWh)	63	40	-78
	(77)	(70)	(75)
	Panel B: Weekday Summer Afternoons		
Merit-Order Change in Net Generation (MWh)	1037	278	853
	(43)	(15)	(35)
Out-of-Merit Change in Net Generation (MWh)	191	22	-193
	(126)	(77)	(107)
	Panel C: High Demand Hours		
Merit-Order Change in Net Generation (MWh)	1214	183	748
	(41)	(29)	(36)
Out-of-Merit Change in Net Generation (MWh)	390	-15	-348
	(141)	(61)	(131)
Observations	2,565,420	306,735	2,202,915
Number of Generating Units	92	11	79
Number of Plants	42	5	43
Total Capacity Represented (MW)	15,498	2,935	11,782

Note: This table was constructed in the same way as Table 3, except that data were also included for February through June of 2013.